COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY CASE NO. PUR-2018-00042

**For revision of rate adjustment clause: Rider U,
new underground distribution facilities,
for the rate year commencing February 1, 2019**

REPORT OF DEBORAH V. ELLENBERG, CHIEF HEARING EXAMINER

November 8, 2018

This case involves the request of Virginia Electric and Power Company ("Dominion" or "Company") for the approval of an annual revision to its rate adjustment clause, referred to as Rider U, related to its Strategic Underground Program ("SUP"). In its application, the Company sought to recover a revenue requirement of $73,047,000 from Virginia jurisdictional customers for the 12-month period beginning February 1, 2019, through January 31, 2020 ("Rate Year"). By the hearing, the Company revised its requested revenue requirement to $71,149,000. The record and, notably, the applicable law supports the approval of an updated Rider U revenue requirement of approximately $69.5 million.

HISTORY OF THE CASE

On March 19, 2018, Dominion filed an application ("Application") and supporting testimony and exhibits with the State Corporation Commission ("Commission") pursuant to § 56-585.1 A 6 ("Subsection A 6") of the Code of Virginia ("Code") as amended by Senate Bill 966, which was passed during the 2018 Virginia General Assembly regular session.[1] Subsection A 6 now mandates cost recovery if defined statutory criteria are met. Through its Application, the Company seeks to recover certain costs associated with its SUP for the Rate Year.

On April 2, 2018, the Commission issued an Order for Notice and Hearing that, among other things: (1) docketed this matter; (2) granted the Company's request for a waiver of 20 VAC 5-201-60 and 20 VAC 5-201-90 of the Commission's Rules Governing Utility Rate Applications and Annual Informational Filings;[2] (3) required the Company to publish notice of the Application; (4) established a schedule for the filing of notices of participation and the submission of prefiled testimony; (5) scheduled a public hearing on the Application for July 24, 2018; (6) granted the Company's request to continue the currently approved Rider U rates at the existing rate of recovery from September 1, 2018, through the effective date of the Rider U update approved in this case; and (7) assigned this case to a Hearing Examiner to conduct all further proceedings on the Commission's behalf and to file a final report.

[1] 2018 Va. Acts Ch. 296 ("SB 966").
[2] Rule 20 VAC 5-201-10 *et seq.*

Concurrent with its Application, the Company filed a Motion for Entry of a Protective Order. On April 9, 2018, a Protective Ruling was entered establishing procedures for the protection of confidential information in this case.

Notices of participation were filed by the Office of the Attorney General, Division of Consumer Counsel ("Consumer Counsel"), the Apartment and Office Building Association of Metropolitan Washington ("AOBA"), and the Board of Supervisors of Culpeper County, Virginia ("Culpeper County").

Written comments supporting the Application were filed by Senator Glen Sturtevant,[3] Delegate Vivian E. Watts,[4] the City Manager of Poquoson,[5] the County Administrator of New Kent County,[6] the County Administrator of York County,[7] and the City Manager of Newport News.[8] Comments were received from Copper Development Association, a not-for profit association of the global copper industry. Four other comments were received from members of the public. All comments supported the SUP.

The hearing was convened, as scheduled, on July 24, 2018. Joseph K. Reid, III, Esquire, Lisa R. Crabtree, Esquire, Lisa S. Booth, Esquire, and Lauren E. Wood, Esquire, appeared on behalf of the Company. Ashley Macko, Esquire, and Alisson Klaiber, Esquire, appeared on behalf of Staff of the Commission ("Staff"). C. Mitch Burton, Jr., Esquire, appeared on behalf of Consumer Counsel. Frann G. Francis, Esquire, and Timothy B. Hyland, Esquire, appeared on behalf of AOBA. Culpeper County notified Staff that it did not intend to participate in the hearing. At the conclusion of the evidentiary hearing, simultaneous post-hearing briefs were directed to be filed on August 28, 2018, which was 21 days after the expected filing date of the hearing transcript. The transcript was not filed on August 7, 2018, as was expected. In consideration of the delay in the availability of the transcript, and in recognition of the Labor Day holiday, a Ruling was entered on August 8, 2018, extending the post-hearing brief filing date to September 7, 2018.

SUMMARY OF THE RECORD

Dominion's Direct Testimony

The Company presented the direct testimony of Alan W. Bradshaw, Director, Electric Distribution Underground for the Company; Leslie M. Carter, Strategic Advisor, Electric Distribution Underground for the Company; C. Alan Givens, Regulatory Consultant in the Regulatory Accounting Department for Dominion; and J. Clayton Crouch, Regulatory Consultant in the Customer Rates Department for Dominion.

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[3] Letter from Glen H. Sturtevant, Jr. 10th District, Senate of Virginia (July 12, 2018).

[4] Online Comments from Vivian E. Watts, 39th District, Virginia House of Delegates (July 17, 2018).

[5] Letter from J. Randall Wheeler, City Manager, City of Poquoson (July 2, 2018).

[6] Letter from Rodney A. Hathaway, County Administrator, New Kent County (July 13, 2018).

[7] Letter from Neil Morgan, County Administrator, York County (July 16, 2018).

[8] Online Comments from Cynthia D. Rohlf, City Manager, Newport News (July 17, 2018).

Mr. Bradshaw offered testimony in support of the Company's request for approval of recovery of the remaining costs of Phase Two of the SUP that were not fully allowed by the Commission in its Final Order dated September 1, 2017, in Case No. PUE-2016-00136,[9] and the costs associated with Phase Three of the SUP.[10]

Mr. Bradshaw testified that in Phase Two, between September 1, 2016, and August 31, 2017, the Company converted roughly 249 miles (679 tap lines) at a cost of $105.2 million, which equated to an average cost per customer of $11,912 and an average cost per mile of $422,496.[11] He stated that, historically, those tap lines experienced 3,553 outage events over a 10-year period at a rate of 14.27 events per mile.[12] He reported that the Commission previously approved Phase Two conversions reflecting a total capital investment of $40 million. According to Mr. Bradshaw, the $65.2 million of the remaining Phase Two costs were eligible for recovery in this proceeding pursuant to SB 966.[13]

He also testified that Phase Three conversions completed or scheduled to be completed between September 1, 2017, and January 31, 2019, were designed to convert approximately 416 miles (1,090 tap lines) of overhead tap lines to underground lines. He stated that the Phase Three capital investment was estimated to be $179 million, which equated to a projected average cost per customer of $13,299 and an average cost per mile of $430,000.[14] He specified that those tap lines experienced approximately 5,815 outage events over the past 10-year period, which equated to an events-per-mile metric of 14.[15]

Mr. Bradshaw represented that all metrics satisfied the Subsection A 6 criteria.

Mr. Carter also testified in support of the Company's proposed annual update to Rider U. He presented a summary of Phase Two expenditures and data. He addressed the actual and projected costs associated with Phase Three, as well as the Company's plans to control and monitor Phase Three costs.[16] He testified that Phase Two began incurring costs on September 1, 2015, with construction commencing on September 1, 2016, and concluding on August 31, 2017. Upon completion, Phase Two resulted in the conversion of 249 miles of overhead tap lines to new underground facilities. He confirmed that the total cost of Phase Two was $105,218,306, which equates to $422,496 per mile. He also represented that 5,797 customers, whose service was fed directly from the converted tap lines, were impacted, with an additional impact to 3,036 customers down line of the converted facilities.[17] He confirmed that the cost per customer for Phase Two conversions was $11,912, and historically those tap lines experienced 3,553 outage events over a

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[9] *Application of Virginia Electric and Power Company, For approval of a rate adjustment clause: Rider U, new underground distribution facilities, for the rate year commencing September 1, 2017*, Case No. PUE-2016-00136, 2017 S.C.C. Ann. Rep. 406 ("2017 Rider U").
[10] Exhibit ("Ex.") 3 (Bradshaw Direct), at 1.
[11] *Id.* at 5.
[12] *Id.* at 5-6.
[13] *Id.*
[14] *Id.* at 7.
[15] *Id.*
[16] Ex. 4 (Carter Direct), at 2.
[17] *Id.* at 3.

10-year period at a rate of 14.27 events per mile.[18] He also noted that the construction costs for the converted miles were close to the planning estimates. The Company estimated a per-mile cost of $450,000. The final cost of $422,496 per mile was comprised of feasibility costs (design, engineering, easement work, and customer communications) totaling $147,160 per mile, and construction costs in the field, which averaged $275,336 per mile.[19]

Mr. Carter next addressed Phase Three. He stated that the Company will underground approximately 1,090 tap lines, equating to roughly 416 miles of overhead lines.[20] He noted that the Company estimated the associated overhead lines converted directly serve 8,578 customers, and another 4,872 customers served down line. He also confirmed that those tap lines experienced approximately 5,815 outage events over the past 10 years.[21] The Company calculated an estimated average cost per mile of $430,000 for Phase Three conversions.

Mr. Carter confirmed that the total capital expenditure requested for recovery in Rider U is approximately $179 million, which equates to a projected average cost per customer of $13,299, an average cost per mile of $430,000, and an event-per-mile metric of 14.[22] He stated that the feasibility activities for Phase Three projects began in April 2016. The actual Phase Three expenses through December 31, 2017, were $83,855,931, which included all stages of conversion, from initial project scoping through design, easement procurement, and construction in the field. Mr. Carter stated the projected Phase Three expenses from January 1, 2018, through January 1, 2019, are $95,024,069.[23]

Mr. Givens provided the details for the proposed revenue requirement calculations. He testified that the Company was proposing a Rate Year of February 1, 2019, through January 31, 2020.[24] The revenue requirement consists of: (1) the total Projected Cost Recovery Factor and the Actual Cost True-Up Factor for the previously approved Phases One and Two of the SUP; (2) Phase Two costs of the SUP not previously approved; and (3) the total projected revenue requirement amount for proposed Phase Three of the SUP.[25] He testified that the Company is also proposing a 9.20% return on common equity ("ROE") as approved by the Commission in its Final Order in the Company's 2017 ROE Proceeding.[26] He did not propose an allowance for Funds Used During Construction Recovery Factor because costs for the SUP are being closed directly to plant in service in the month incurred.[27] The Company was proposing an Actual Cost True-Up Factor for the calendar years 2016 and 2017.[28] He noted that the Company was also proposing to include only

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[18] *Id.* at 4.
[19] *Id.*
[20] *Id.* at 5.
[21] *Id.*
[22] *Id.*
[23] *Id.* at 6.
[24] Ex. 7 (Givens Direct), at 3.
[25] *Id.* at 1-3.
[26] *Id.* at 3; *Application of Virginia Electric and Power Company, For the determination of the fair rate of return on common equity to be applied to its rate adjustment clauses*, Case No. PUR-2017-00038, 2017 S.C.C. Ann. Rep. 475 ("2017 ROE Proceeding").
[27] Ex. 7 (Givens Direct), at 5.
[28] *Id.* at 5-6.

actual and projected capital expenditures up until the beginning of the Rate Year to determine the rate base and calculate financing costs on the rate base. Thus, the projected rate base as of January 31, 2019, was utilized for each phase.[29] He also testified that the Company was using its actual December 31, 2017, year-end capital structure and cost of capital for purposes of setting rates.[30] He noted that the Company proposed to defer depreciation expenses, property taxes, feasibility costs, and financing costs on rate base incurred up through the beginning of the Rate Year for Phase Three.[31] He added that the revenue requirement to be recovered from Virginia jurisdictional customers through the Projected Cost Recovery Factor will consist of financing costs on invested capital through January 31, 2019, plus income taxes on the equity component of the return for each phase of the SUP. He explained that the financing costs portion of the revenue requirement for each phase is calculated by multiplying the projected rate base for the month ending January 31, 2019, by the Company's cost of capital.[32]

He testified that the total actual revenue requirement for 2016 and 2017 was $29.672 million, and actual revenue received from customers during 2016 and 2017 was $23.951 million. This resulted in a net under-recovery for 2016 and 2017 of $5.721 million.[33] The financing costs for that under-recovery was $0.246 million. Therefore, the revenue requirement for the Actual Cost True-Up Factor requested for recovery in the Rate Year was $5.967 million.[34] Phases One and Two costs consist of the Projected Cost Recovery Factor of $13.991 million, the Actual Cost True-Up Factor of $5.967 million minus $1.8 million, the final of three voluntary customer credits related to Phase One projects and as agreed to in the 2016 Rider U proceeding.[35] The Projected Cost Recovery Factor revenue requirement amount for the remaining Phase Two costs and for Phase Three totaled $54.889 million.[36]

Mr. Givens initially testified that the proposed jurisdictional revenue requirement of $73.047 million consisted of $18.158 million for previously approved Phase One and Phase Two costs and $54.889 million for the remaining, previously disallowed, Phase Two costs and proposed Phase Three costs.[37] Finally, Mr. Givens testified that the Company is also proposing a new Virginia jurisdictional allocation factor methodology to be used at the start of the Rate Year, which resulted in an allocation factor of 92.3353%.[38]

Mr. Crouch discussed the proposed allocation of Rider U plant to customers in Virginia. He testified that in the Company's opinion, the costs of the SUP should be allocated to eligible Virginia jurisdictional and Virginia non-jurisdictional customers since the SUP is intended to

[29] *Id.* at 6.
[30] *Id.* at 7.
[31] *Id.* at 8.
[32] *Id.* at 9.
[33] *Id.* at 12.
[34] *Id.* at 13.
[35] *Id.* at 14; *Application of Virginia Electric and Power Company, For approval of a rate adjustment clause: Rider U, new underground distribution facilities for the rate year commencing September 1, 2016*, Case No. PUE-2015-00114, 2016 S.C.C. Ann. Rep. 305 ("2016 Rider U").
[36] Ex. 7 (Givens Direct), at 14.
[37] *Id.* at Schedule 1, Schedule 2 at 1.
[38] *Id.* at 7.

benefit those customers.[39] The Company also contended that the law precludes costs from being allocated to, or recovered from, the Company's large general service class customers.[40]

The Company proposed a new method of cost allocation between the Virginia jurisdictional and Virginia non-jurisdictional customers.[41] Mr. Crouch utilized distribution cost of service information, recognized the cost caused by actual plant investment incurred for SUP, and recognized that large general service class customers should not be allocated any costs for the purpose of recovery under Rider U.[42] He stated that the starting point for the proposed jurisdictional allocation factor was the 2016 end-of-period cost of service study ("2016 COSS"). Mr. Crouch noted that he intended to update the allocation factor to reflect the 2017 end-of-period cost of service study ("2017 COSS") when it was available.[43] The Company used a Virginia jurisdictional allocation factor of 92.3353% for the Projected Cost Recovery Factor.[44]

Based on the Commission's previously approved methodology in the 2017 Rider U, the Company used a Virginia jurisdictional allocation factor of 89.1650% for the Actual Cost True-Up Factor.[45]

Mr. Crouch testified that implementation of the proposed Rider U on February 1, 2019, will incrementally increase the residential customer's monthly bill by $1.39 over the current Rider U adjustment. The total Rider U bill impact will be $1.98 based on usage of 1,000 kWh.[46]

AOBA's Testimony and Exhibits

Bruce R. Oliver, President of Revilo Hill Associates, Inc., offered testimony on behalf of AOBA.[47] He testified that on the basis of data for the period ended December 31, 2016, the Company allocated 92.3353% of the total costs for undergrounding facilities to Virginia jurisdictional service, and 7.6647% of the costs to Virginia non-jurisdictional service.[48] Mr. Oliver, however, testified that the undergrounding activities for which costs are recovered through Rider U are predominantly secondary distribution lines, conduit, transformers and services that serve geographically specific portions of the Company's service territory or individual customers. For this reason, he believes costs recovered through Rider U should be booked on a *situs* basis.[49] According to Mr. Oliver, few of the undergrounded facilities' costs should be shared by Virginia jurisdictional and Virginia non-jurisdictional customers.[50]

[39] Ex. 8 (Crouch Direct), at 1-2.
[40] *Id.* at 3.
[41] *Id.* at 4.
[42] *Id.*
[43] *Id.* at 5-7.
[44] *Id.* at 7.
[45] *Id.*
[46] *Id.* at 11.
[47] Ex. 11 (Oliver).
[48] *Id.* at 5.
[49] *Id.* at 6.
[50] *Id.*

Mr. Oliver also contended that the Company's proposed rate design for GS-2 and GS-2T customers is not reasonable or appropriate.[51] He testified that the proposed charges apply a higher cost per kW for GS-2 and GS-2T customers with load factors greater than 50% than for lower load factor customers within the same class.[52] He asserted that the result is not cost-based and penalizes higher load factor usage.[53] He offered an analysis which demonstrated that the effective cost per kW for customers with higher load factors is more than 45% above that for lower load factor GS-2 and GS-2T customers. He represented that the Company's proposed methodology produces an average adjusted charge per kW for high load factor customers of $0.383 per kW. By comparison, he stated that the effective cost per kW for low load factor GS-2 and GS-2T customers is $0.264.[54]

He argued that Rider U charges for GS-2 and GS-2T customers should start with a uniform allocation of costs on a dollars-per-kW basis. A uniform allocation for all GS-2 and GS-2T kW demands reflects a cost of $0.325 per kW.[55]

Consumer Counsel's Testimony and Exhibits

Consumer Counsel offered the testimony of **Scott Norwood**, President of Norwood Energy Consulting, L.L.C. The purpose of Mr. Norwood's testimony was to present his findings and recommendations regarding Dominion's request for approval of revisions to Rider U to recover costs of the SUP for the Rate Year. He identified the rate impact as follows:

Rate Impact Summary for Virginia Residential Customers[56]

Year	Revenue Requirement Rate Year Total	Residential Allocation Factor	Allocated Revenue Requirement	1000 KWH Monthly Residential Bill
2019	$73,047,087	77.8077%	$56,836,246	1.98
2020	$71,055,625	77.8077%	$55,286,735	1.93
2021	$88,539,187	77.8077%	$68,890,289	2.40
2022	$105,165,547	77.8077%	$81,826,875	2.85
2023	$120,486,260	77.8077%	$93,747,567	3.27
2024	$135,366,339	77.8077%	$105,325,411	3.67
2025	$149,753,383	77.8077%	$116,519,637	4.06
2026	$163,728,247	77.8077%	$127,393,155	4.44
2027	$177,214,274	77.8077%	$137,886,320	4.81
2028	$190,263,358	77.8077%	$148,039,509	5.16

Mr. Norwood noted, under the provisions of SB 966, overhead tap line conversions that meet certain eligibility criteria are deemed to provide local and system-wide benefits, to be cost

[51] *Id.* at 9.
[52] *Id.*
[53] *Id.*
[54] *Id.* at 9, Ex. 12 (Oliver Updated Schedule 1), at 4.
[55] *Id.* at 10.
[56] Ex. 13 (Norwood), at 6 (based on the Company's proposed revenue requirement in its Application).

beneficial, and costs associated with such conversions are deemed to be reasonable and prudent.[57] Therefore, he testified that the primary issues in this case are whether the Phases Two and Three SUP lines not previously approved for cost recovery meet the eligibility requirements under Subsection A 6, as amended by SB 966, for approval through Rider U, and whether the cost allocation and rate design are reasonable.[58]

Mr. Norwood testified that based on his review of the tap line data provided by Dominion in response to Staff Interrogatory 5-48,[59] it appeared that all the Phase Three tap lines were or will be converted after September 1, 2016. However, he stated that the data indicated that eight Phase Two tap lines were converted before September 1, 2016, and the total cost of those eight lines was approximately $1.239 million.[60] He noted that the Commission's Final Order in the 2017 Rider U proceeding concluded that it was reasonable to allow Dominion to recover $40 million of the total costs of the Phase Two pilot program, but found that the balance of the $110 million requested for Phase Two recovery was not cost beneficial or just and reasonable.[61] Mr. Norwood testified that although the provisions of SB 966 deems SUP projects completed on or after September 1, 2016, to be cost beneficial and prudently incurred, those provisions do not apply to projects completed before September 1, 2016. He, therefore, recommended that the $1.239 million Dominion expended on the eight Phase Two projects converted before September 1, 2016, be disallowed.[62]

He next testified that assuming Dominion's outage history data is accurate, it appeared the nine or more average unplanned events-per-mile criteria was met by the Phases Two and Three SUP tap line projects. However, he was unable to confirm the accuracy of the unplanned event data.[63] Similarly, based on his review of the data provided by Dominion, the average cost of the Phases Two and Three SUP projects was approximately $425,779 per mile and $416,192 per mile, respectively.[64] He stated that while those amounts are based on unaudited tap line mileage data, he did not expect any inaccuracies in the data to be significant enough to make the actual cost per mile for SUP line conversions exceed the eligibility limit.[65]

Similarly, he offered testimony that Dominion's average cost-per-customer amounts appeared to meet the eligibility criteria, however, he was not able to confirm the accuracy of Dominion's data.[66]

Mr. Norwood expressed concern that the Dominion data for Phases Two and Three lines included more than 116 tap lines with no unplanned outage events, and 11 lines that did not serve any customers, directly or indirectly, over the historical 10-year period used for selecting SUP

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[57] *Id.*
[58] *Id.*
[59] Ex. 5.
[60] Ex. 13 (Norwood), at 8, attached Ex. SN-2.
[61] *Id.*; 2017 Rider U, at 410.
[62] Ex. 13 (Norwood), at 8-9.
[63] *Id.* at 9.
[64] *Id.* at 11.
[65] *Id.*
[66] *Id.* at 12.

projects.[67] He was concerned that those conversions were either not justified, or may reflect inaccurate data due to the Company's failure to audit the tap line data.[68] He testified that the total conversion cost of the tap lines with no unplanned outage events over the 10-year historical period and the 11 tap lines that did not serve any customers was approximately $9.608 million and $0.572 million, respectively.[69]

He observed that the Company sought to assign 92.3353% of the total Rate Year cost of the proposed SUP projects to the jurisdictional customers in its Virginia service territory.[70] He testified that Dominion is proposing a new cost allocation method whereby 100% of Rider U costs would be allocated to customers in its Virginia service territory, excluding large general service rate classes that are exempted from SUP charges.[71]

Mr. Norwood took exception to the Company's proposal to allocate all the SUP costs to the Company's Virginia service area. He quoted SB 966 which provides that the costs of SUP investment that meet certain eligibility criteria are deemed to provide local and system-wide benefits, and to be cost beneficial and prudently incurred.[72] Mr. Norwood noted that power plants located in Virginia are found to provide system-wide capacity and demand related benefits; and, therefore, the costs associated with power plants are allocated to all eligible customers served by Dominion. According to Mr. Norwood, SUP investments are fundamentally different from Dominion investments in new distribution lines located in Virginia that provide little or no system-wide benefits, but should be treated like power plants that also provide system-wide benefits.[73]

Staff's Testimony and Exhibits

Staff submitted the testimony of David J. Dalton, Utilities Analyst in the Commission's Division of Public Utility Regulation ("PUR"); Nicholas M. Upton, Utilities Engineer in PUR; Estaña M. Davis, Principal Utility Accountant with the Commission's Division of Utility Accounting and Finance ("UAF"); and Phillip M. Gereaux, Senior Utility Analyst in UAF.

Mr. Dalton provided an overview of prior Rider U proceedings, and the Company's Application, including the Company's proposed jurisdictional revenue apportionment, class revenue apportionment, and rate design. He addressed the requirements of Subsection A 6, and examined whether Phase Two, including the remaining Phase Two projects and proposed Phase Three projects, comply with certain new statutory cost parameters.[74] He testified that Staff calculated the average cost per direct and down line customer of Phase Two, including feasibility costs, to be approximately $11,996. Staff calculated the average cost per mile of Phase Two, including

[67] *Id.* at 12-13.
[68] *Id.* at 13.
[69] *Id.*
[70] *Id.*, citing Ex. 8 (Crouch Direct), at 7.
[71] Ex. 13 (Norwood), at 14.
[72] *Id.*
[73] *Id.* at 14-15.
[74] Ex. 22 (Dalton), at 1.

feasibility costs, to be approximately $425,471.[75] He opined that the average costs, therefore, appear to meet the statutory limits of $20,000 per customer and $750,000 per mile.

The Company also seeks approval of Phase Three SUP projects. Mr. Dalton calculated the average cost per customer for the Phase Three projects completed as of April 24, 2018, including feasibility costs, to be approximately $13,873, and the average cost per mile to be $394,215.[76] He noted that those average costs also appear to meet the statutory criteria.[77] Mr. Dalton reviewed the actual and estimated costs for the Phase Three projects converted as of May 18, 2018, and those scheduled for conversion. Staff calculated an average cost per customer, including feasibility costs, of approximately $12,767, and the average per-mile cost to be approximately $416,192, which also meets the statutory criteria.[78]

Staff, however, reviewed the projects individually and noted that when viewed in isolation a number of projects appeared to be "unduly costly."[79] Seven Phase Two projects had all-in costs per customer ranging from $159,710 to $251,625.[80] Similarly, seven Phase Three projects had all-in costs per customer ranging from $188,748 to $299,149.[81] He observed that in many cases the lifetime revenue requirement per customer exceeded the median sales price of homes in the City of Richmond.[82]

Mr. Dalton testified that Staff maintains the position that it may be appropriate for the Company to consider customer counts when selecting tap lines for conversion as part of future phases of the SUP to maximize the number of customers directly and indirectly benefiting from the conversions. He stated that if the Company excluded high-cost, low customer count projects in future phases of the SUP the economic efficiency of the SUP would be improved.[83]

Mr. Dalton next addressed the Company's proposed jurisdictional allocation methodology. He testified that Staff does not agree with the Company's modifications to the previously approved methodology. Further, he represented that the Company's proposal is essentially the same methodology the Company proposed, and the Commission rejected, in the 2016 Rider U proceeding.[84] Mr. Dalton recommended the Commission use the same jurisdictional cost allocation methodology approved by the Commission in the 2016 Rider U case, and used again in the 2017 Rider U case.[85]

Staff disagreed with the Company's proposal to use the 2017 COSS. Staff recommended that the Commission continue to use the cost of service study developed in the 2015 Biennial

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[75] *Id.* at 4.
[76] *Id.* at 5.
[77] *Id.*
[78] *Id.* at 5-6.
[79] *Id.* at 6.
[80] *Id.*
[81] *Id.* at 8.
[82] *Id.*
[83] *Id.* at 8-9.
[84] *Id.* at 11; 2016 Rider U.
[85] *Id.*

Review,[86] using Federal Energy Regulatory Commission ("FERC") Accounts 364, 365, 366, 367, 368, 369, and 373, as the basis for the Rider U Virginia jurisdictional allocation factor. Staff contended that the 2015 Biennial Review was the most recent opportunity Staff and other parties had to fully review and litigate the Company's data.[87] Staff's recommended Virginia jurisdictional allocation factor is 89.4487%, as was approved in the 2016 Rider U case.[88]

Mr. Dalton also disagreed with the Company's proposed class cost allocation of the Virginia jurisdictional revenue requirement, which is based on the same general methodology as the Company used in the 2017 Rider U case with one modification.[89] The Company proposed to allocate the revenue requirement among the classes based on each class' 2016 Rider U-relevant distribution plant weighted to reflect the actual Rider U plant investment in the same manner that the Company proposed in the development of the Rider U Virginia jurisdictional allocation factor. Mr. Dalton testified that the proposed methodology is essentially the same methodology that the Company proposed, and the Commission rejected, in the 2016 Rider U case.[90]

Furthermore, he noted that a residential customer using 1,000 kWh of electricity per month would see an increase in their monthly bill of approximately $1.39 during the Rate Year, if the Commission approves the Company's proposed rates.[91] He added, however, that the Company estimated that the monthly bill impact for a residential customer using 1,000 kWh per month for the whole of the SUP, through 2028, to be $5.16.[92]

Mr. Dalton recommended that should the Commission approve a revenue requirement that differs from the Company's requested amount of $73,047,000 for the Rate Year the Rider U rates should be adjusted proportionately to maintain the class revenue apportionment and rate design methodology proposed by Staff.[93]

Mr. Upton addressed the Company's program design, customer-related issues and information, and evaluation of reliability improvements and data.[94] Mr. Upton described the Company's program design, stating that the Company plans to convert approximately 416 miles of overhead tap lines and facilities to underground. He noted that the Company stated the Phase Three lines have an average events-per-mile metric of 14, an average cost per customer of $13,299, and an average cost per mile of $430,000. He further noted that the Company anticipates that conversion of approximately 1,090 tap lines that directly serve 8,578 customers, and an additional 4,872 customers indirectly.[95] He noted that the Company continues to use the "events-per-mile" metric to

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[86] *Application of Virginia Electric and Power Company, For a 2015 biennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUE-2015-00027, 2015 S.C.C. Ann. Rep. 299 ("2015 Biennial Review").
[87] Ex. 22 (Dalton), at 11-12.
[88] *Id.* at 15.
[89] *Id.* at 11.
[90] *Id.* at 17-18.
[91] *Id.* at 19-20.
[92] *Id.* at 20.
[93] *Id.*
[94] Ex. 21 (Upton), at 2.
[95] *Id.* at 6.

identify and select candidate tap lines for underground conversions. He reported that once candidate lines are identified, a field review is done to determine if there have been any recent system improvements that may require changes to the planned course of action. Additionally, the Company considers whether to add adjacent tap lines to a project to avoid an unintended consequence of differing levels of reliability within the same area.[96] He also noted, and supported, the Company's consideration of conversions of poorly performing portions of longer tap lines. He, however, stated that the Company does not consider the number of customers served by a tap line in considering whether to include it in the SUP. Staff continues to believe that in order to maximize the benefit of the SUP, the Company should maximize the number of customers that benefit either directly or indirectly from the program.[97] Mr. Upton contended that the tap line selection process would be improved if it better mirrored the Company's restoration strategy and incorporated customer count in the selection process.[98] He also noted that the selection process counts events per mile, but is silent with respect to the duration of an event.[99] He stated that Staff recommended this approach in the 2017 Rider U case and continues to believe that it would provide greater benefits.[100]

Mr. Upton observed that approximately 95.6% of customers to be served by Phase Three conversions are residential. Additionally, the Company estimated that the jurisdictional split is approximately 99.5% Virginia jurisdictional and 0.5% Virginia non-jurisdictional.[101] He also observed that the SUP for all phases appears to be well-distributed across the Company's Virginia service territory.[102] Mr. Upton noted that Phases Two and Three include a higher percentage of long tap lines and subdivision projects than Phase One. Conversions with higher customer density require obtaining more easements and installing an increased number of transformers and other equipment, which results in higher costs.[103]

Mr. Upton next testified that the SUP appears to have had a positive impact on the reliability of the converted tap lines, because they have experienced fewer and shorter interruptions.[104] He stated, however, that the Company does not provide enough information to determine the impact on system reliability. Staff recommended the Company be required to provide additional data to improve measurement and tracking of the reliability benefits of the SUP on an annual basis.[105] Specifically, he recommended the following information be provided for each tap line converted or proposed for conversion to underground:

(1) Tap line/devise identifier;
(2) Date tap line converted to underground (or projected date to be converted);
(3) Tap line length;
(4) Number of direct customers served;

[96] *Id.* at 6-7.
[97] *Id.* at 8, 10.
[98] *Id.* at 11.
[99] *Id.*
[100] *Id.* at 12.
[101] *Id.*
[102] *Id.* at 13.
[103] *Id.* at 14.
[104] *Id.* at 17.
[105] *Id.* at 20-22.

(5) Number of indirect customers served;
(6) Cost to convert tap line to underground (excluding feasibility cost);
(7) Feasibility cost;
(8) Average cost per direct customer to convert tap line to underground (excluding feasibility cost);
(9) Average cost per customer to convert tap line to underground (including both directly served and down line customers, excluding feasibility cost);
(10) Average cost per direct customer to convert tap line to underground (including feasibility cost);
(11) Average cost per customer to convert tap line to underground (including both directly served and down line customers and including feasibility cost);
(12) Total number of unplanned outages on tap line during the ten years preceding conversion (excluding major storms);
(13) Total number of unplanned outages on tap line during the ten years preceding conversion (including major storms);
(14) Year 1 post-conversion tap line outage count (as applicable);
(15) Year 2 post-conversion tap line outage count (as applicable); and
(16) Year 3 post-conversion tap line outage count (as applicable).[106]

Ms. Davis addressed the Company's actual and projected SUP capital costs associated with Phases One, Two, Three, and future phases; Staff's recommended Rider U revenue requirement for the Rate Year; the revenue requirement impact of Staff Witness Dalton's recommended jurisdictional factor and the most expensive projects per customer for each of Phase Two and Three; Staff's audit of the Company's actual SUP capital costs incurred through January 31, 2018; and the annual investment limit for new underground facilities prescribed by Subsection A 6.[107] She testified that there are three categories of capital costs included for recovery in the current Rider U Application: (1) costs associated with the previously approved phases of the SUP; (2) remaining Phase Two costs; and (3) costs associated with Phase Three of the SUP.[108] She reported that the Company estimated the lifetime Rider U revenue requirement associated with Phases One, Two, and Three, over the approximately 42-year useful lives of the underground distribution plant, are approximately $313.8 million for the previously approved phases, $154.8 million for the remaining Phase Two, and $454.2 million for Phase Three.[109]

Ms. Davis stated that Staff recommended a total combined annual Rider U revenue requirement for the Rate Year of $70.8 million, which includes $17.6 million for the previously approved phases, $15.8 million for the remaining Phase Two, and $37.4 million for Phase Three.[110] Staff's recommended revenue requirement consists of a Projected Cost Recovery Factor and an Actual Cost True-Up Factor for the previously approved phases and only a Projected Cost Recovery Factor for the remaining Phase Two costs not previously approved and Phase Three costs.[111]

[106] Ex. 5.
[107] Ex. 19 (Davis), at 2-3.
[108] *Id.* at 3.
[109] *Id.* at 3-4.
[110] *Id.* at 7.
[111] *Id.*

Ms. Davis explained that there are three differences between Staff's and the Company's revenue requirement. First, Staff used a corrected December 31, 2017, capital structure as suggested by Staff Witness Gereaux. Second, Staff used an 89.45% jurisdictional allocation factor as recommended by Staff Witness Dalton. Third, Staff made corrections to the calculation of cash working capital.[112]

She observed that both the Company and Staff incorporated the new federal income tax rate in the Rider U revenue requirement as well as a separate line item to include the excess deferred income tax impact.[113]

She testified the Company continues to incur capital costs associated with future SUP phases and may request recovery of and a return on such costs in the future. In total, she noted that the Company projected that it will incur $492.8 million of cumulative SUP capital costs through January 31, 2019, and $631.2 million of cumulative SUP capital costs through January 31, 2020.[114] She also noted that the total lifetime revenue requirement of the entire SUP is approximately $5.8 billion, which includes recovery of and a return on approximately $2 billion of capital costs.[115]

Staff also calculated the impact of Staff Witness Dalton's recommended jurisdictional factor to be a reduction of $5.4 million to Staff's recommended Rider U revenue requirement for the Rate Year.[116]

Ms. Davis observed that the total per-customer lifetime revenue requirement of the seven most expensive SUP projects for Phases Two and Three were approximately $3.4 million and $1.4 million, respectively.[117]

She noted that Staff will continue to review Rider U costs as they are incurred, and monitor the Company's tracking of such costs on its books, review the Company's accounting and ratemaking for Rider U costs, and make recommendations related thereto.[118]

She stated that the 2014 distribution rate base is $3.923 billion, on a thirteen-month average and adjusted to a regulatory accounting basis. Based on that rate base, Staff recommended that the Commission set the annual incremental investment limit, as prescribed by Subsection A 6, at $196.2 million.[119]

Ms. Davis supplemented her testimony to revise Staff's recommended revenue requirement to (i) correct certain cash working capital calculations and the accumulated deferred income tax on the balance of deferred costs, (ii) utilize the overall cost of capital based on the updated December 31, 2017, capital structure discussed by Staff Witness Gereaux, and (iii) incorporate Company

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[112] *Id.* at 8.
[113] *Id.* at 9.
[114] *Id.* at 13.
[115] *Id.*
[116] *Id.*
[117] *Id.* at 14.
[118] *Id.*
[119] *Id.*

Witness Givens' corrections to Rate Year property tax expense and removal of the Rate Year feasibility expense associated with cancelled projects.[120] Staff's revised recommended revenue requirement for Rider U is $69.9 million, which is approximately $924,000 lower than Staff's original recommended revenue requirement.[121] The comparison of Staff's recommended revenue requirement with that of the Company's revised revenue requirement is as follows:[122]

Comparison of Company and Staff
Revenue Requirements for the Rate Year
(In Thousands)

	Staff	**Company Rebuttal**
Previously Approved Phases (One and Two)		
Projected Cost Recovery Factor	$13,545	$14,091
Actual Cost True-Up Factor	$5,885	$5,868
Less: Final Voluntary Customer Credit per 2016 Rider U	$(1,800)	$(1,800)
	$17,630	**$18,159**
Remaining Phase Two		
Projected Cost Recovery Factor	**$15,865**	**$16,094**
Phase Three		
Projected Cost Recovery Factor	**$36,410**	**$36,937**
Total	**$69,905**	**$71,190**

Mr. Gereaux addressed the Company's proposals with respect to capital structure and ROE. He observed that the Company used its December 31, 2016, capital structure for the Actual Cost True-Up Factor for calendar years 2016 and 2017.[123] For determining the Actual Cost True-Up Factor for calendar year 2017 and the Projected Cost Recovery, the Company proposed to use its December 31, 2017, ratemaking capital structure. Staff agreed with the weights and cost rates used by the Company for the December 31, 2016, capital structure. Mr. Gereaux also agreed with the Company's proposal to use a December 31, 2017, capital structure and with the weights proposed by the Company. He, however, disagreed with the cost rates for short-term and long-term debt. Staff proposed using a 3-month average cost rate of 1.570%, consistent with past Commission precedent. He also recommended use of an annual yield-to-maturity calculation for each individual note.[124]

For calculating the Actual Cost True-Up Factor, Mr. Gereaux also supported the Company's proposal to use an ROE of 9.6% for August 2016 to August 2017; an ROE of 9.4% for September 2017 to November 28, 2017; and an ROE of 9.2% for November 29, 2017, to December 2017.

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[120] Ex. 20 (Davis Supplemental), at 2.
[121] *Id.*
[122] *Id.* at Supplemental Schedule 1.
[123] Ex. 17 (Gereaux), at 1.
[124] *Id.* at 2-3.

Mr. Gereaux supplemented his testimony to accept the Company's cost of long-term debt, and address the Company's acceptance of his calculation for short-term debt outstanding.[125]

Additionally, he supported use of an ROE of 9.2% for the Projected Cost Recovery Factor.[126]

The Company's Rebuttal

On rebuttal, Dominion submitted the testimony of Messrs. Bradshaw, Carter, Givens, and Crouch.

Mr. Bradshaw offered rebuttal testimony to respond to Staff Witnesses Upton and Dalton, and Consumer Counsel Norwood. He described the objectives of the SUP and demonstrated how the removal of outage prone tap lines reduces the amount of work activities to be performed in a restoration effort, creating a cascading benefit to the Company's restoration process and benefits a much broader group of customers than those served by converted tap lines. He, therefore, disagreed with Staff's assertion that utilizing customer count as the tap line selection criteria would provide a better outcome for the SUP.[127] He stated that the General Assembly has dictated the required reliability metric to be used for selection of tap lines.[128]

He testified that the Company utilizes a variety of programs to maximize the performance of the electric distribution grid.[129] Some are primarily focused on reducing the System Average Interruption Duration Index ("SAIDI"). He further testified that the Company's investment over the last decade has led to an overall decrease in SAIDI (excluding major storms).[130] He asserted that the completed conversion projects have already led to a reduction in outage events on the undergrounded tap lines.[131] According to Mr. Bradshaw, undergrounding tap lines leads to a cascading reduction of the total length of restoration. A primary objective of the SUP is to reduce the number of restoration activities be accomplished in a restoration effort.[132] Mr. Bradshaw testified that the SUP is eliminating repair locations requiring additional resources due to the inability to utilize bucket trucks and augers because of access limitations.[133]

Mr. Bradshaw next addressed Staff Witness Upton's recommendation that the selection process should include customer count considerations to mirror the restoration process.
Mr. Bradshaw testified that Staff appeared to overlook two important factors crucial to reducing the total length of restoration for a much broader group of customers than those served by the converted

[125] Ex. 18 (Gereaux Supplemental), at 2.
[126] Ex. 17 at 4.
[127] Ex. 24 (Bradshaw Rebuttal), at 1-2.
[128] *Id.* at 4.
[129] *Id.* at 5.
[130] *Id.*
[131] *Id.* at 7.
[132] *Id.*
[133] *Id.* at 8.

lines.[134] He opined that if the Company used the higher customer count rather than the historical outage-event data, it would likely lessen the impact of the SUP because, in comparison to historical outage-event frequency, customer count has little correlation to identifying potential future work repair locations.[135] Second, Mr. Bradshaw stated that ,while Staff agreed that the SUP should be implemented across the entire Virginia territory, Staff did not account for how the geographic dispersion greatly enhances resource efficiency.[136] Mr. Bradshaw clarified that when looking at the system-wide restoration effort, different areas within the Company's service territory are at different stages of the restoration hierarchy. Some areas are completing transformer and service restoration, while other areas are still working on critical services and main feeders.[137] He added that the benefit of the SUP is that in addition to the Company's traditional resource planning, resources in less impacted areas can be redeployed earlier to heavier impacted areas.[138]

Mr. Bradshaw next turned to Staff Witness Dalton's testimony that the costs per customer related to 14 tap lines converted to underground during Phases Two and Three had high costs per customer. Mr. Bradshaw stated that Mr. Dalton's analysis had key omissions.[139] While he referred to Company Witness Carter for further discussion, he noted that Phases Two and Three of the SUP will convert nearly 1,800 tap lines that in the aggregate have an average cost per customer well under the statutory thresholds. Additionally, the 14 tap lines highlighted by Staff comprise less than 1% of total Phases Two and Three tap lines.[140] Several of the tap lines highlighted by Staff were part of larger projects that included additional tap lines and customers.[141] Mr. Bradshaw contended that Staff's analysis of customer count and cost data ignored the operational value of the conversion of the 14 tap lines. Notably, he testified, there have been 190 outage events over the past ten years on the projects that included the 14 tap lines, equating to an event-per-mile ratio of 12.22.[142] Finally, he noted that properly assessing the value of a tap line for conversion should include the impacts of tree canopy, access, topography, and input from local office personnel.[143] He noted that each of the 14 tap lines highlighted had exposure to tree canopies, several ran through swamps or ravines, and several others were located in mountainous topography. Many, he stated, were not accessible by vehicle and would require additional resources to accomplish restoration. Mr. Dalton did not consider the field conditions for the 14 tap lines.[144]

Mr. Bradshaw responded to Consumer Counsel Witness Norwood's concerns related to the data utilized to inform the SUP and offered an overview of the systems and controls that are used to generate this data.[145] He recognized that isolated human performance errors exist in most processes, but the Company uses robust and integrated systems that utilize control processes and

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[134] *Id.*
[135] *Id.* at 8-9.
[136] *Id.* at 9.
[137] *Id.* at 10.
[138] *Id.*
[139] *Id.* at 14.
[140] *Id.*
[141] *Id.*
[142] *Id.* at 14-15.
[143] *Id.* at 15.
[144] *Id.*
[145] *Id.*

procedures to mitigate the impact from potential isolated human performance errors,[146] such as the Outage Management System.[147] He emphasized that unplanned outage events are heavily informed through customer notifications.[148]

Mr. Norwood had also expressed concern about the availability of audited outage event data for SUP Phases Two and Three.[149] In response, Mr. Bradshaw stated that following the completion of outage restoration activities, every outage event project goes through a thorough project audit process which includes outage cause, outage durations, protective zone impacted, and number of customers impacted. The verification process includes reviews of circuit switching orders, crew and analyst project notes recorded during the repair process, and repair completion times.[150]

Mr. Carter addressed the testimonies of Staff Witnesses Dalton, Upton, and Davis, as well as Consumer Counsel Witness Norwood.[151]

Mr. Carter updated Phase Three costs, noting that approximately 80% of Phase Three projects had either been completed or were in progress. He testified that the Company was on track to convert 416 miles of tap line in Phase Three.[152] He stated that Phase Three costs were projected to be approximately $414,000 per mile, $12,563 per customer and 14 events per mile; all of which meet the statutory criteria for recovery.[153] He further stated that the remaining 20% of the projects in Phase Three had been designed, but not yet released, and were expected to have similar cost, customer and event characteristics to those projects completed or in progress.[154]

He next responded to Mr. Dalton's testimony that certain projects appeared to have higher than average costs when considered on a per customer basis. He reiterated that the statutory criteria are calculated on a subset of tap lines and do not limit costs on any one individual line.[155] He believed that approach creates a balance by looking at averages.[156] He noted that the higher costs per customer conversion projects highlighted by Staff focused on only one metric, the cost per customer, while ignoring the event count, and, therefore, does not tell the whole story behind a project.[157] He represented that in the Company's opinion, focusing on higher customer density projects will drive up the cost per mile.[158] He also testified that it could limit the number of miles converted and the total outage events removed from the system.[159] He explained that future phases of the SUP are expected to include more subdivision projects, which will lead to an organic increase

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[146] *Id.*
[147] *Id.* at 16.
[148] *Id.* at 18.
[149] *Id.* at 21.
[150] *Id.*
[151] Ex. 25 (Carter Rebuttal), at 1.
[152] *Id.* at 3.
[153] *Id.*
[154] *Id.*
[155] *Id.* at 3-4.
[156] *Id.* at 4.
[157] *Id.*
[158] *Id.* at 5.
[159] *Id.*

in customer density. He also discussed why customer count and outage duration are not appropriate selection criteria when identifying tap lines for conversion.

Mr. Carter responded to Staff Witness Upton's testimony that the events-per-mile metric does not account for the duration of each interruption.[160] He testified that Staff's suggestion would not yield greater system benefits than only using the events per mile, which is the statutory metric.[161] He responded to Mr. Upton's suggestion that the Company be required to include additional data, regional and system-wide SAIDI, System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI"), in the SUP Annual Report. Mr. Carter affirmed the Company's commitment to provide Staff with any relevant and useful information to assess the effectiveness of the SUP, and proposed that the Company and Staff meet to develop a mutually agreeable list of data and analysis to provide going forward.[162]

He also corrected Staff Witness Davis' table of cumulative SUP capital costs through January 31, 2018.[163] Mr. Carter stated that the actual feasibility costs for Phase Three through April 30, 2018, shown as zero should be $58.2 million. [164]

In response to Mr. Norwood, Mr. Carter pointed out that the differences between Mr. Norwood's cost analysis and the numbers in the Company's direct testimony were due to the timing of the information provided. He also addressed the eight converted tap lines that Mr. Norwood recommended be ineligible for recovery.[165] He advised that the Company does not consider a tap line project "closed" until all associated accounting has been finalized, and all eight tap lines were "closed" to the Company's fixed asset account after September 1, 2016.[166] Mr. Carter also testified that the Company updates customer count changes on a daily basis, along with corrections or amendments to circuitry. Therefore, the Company's latest information is the most accurate and relevant.[167] Additionally, he stated that all of the tap lines identified by Mr. Norwood as experiencing no unplanned outage events were tap lines adjoining or adjacent to tap lines previously selected for inclusion in the SUP.[168]

Mr. Givens updated the Company's proposed revenue requirement based upon four adjustments identified by Staff Witnesses Davis, Dalton and Gereaux.[169] Specifically, the Company corrected its calculations of cash working capital as identified by Ms. Davis; adjusted the short-term debt cost rate as recommended by Mr. Gereaux; accepted Staff's methodology calculating financing costs on deferred cost balances using a rolling two-month average balance; and incorporated Staff's consolidated cash working capital calculations where applicable.[170] His updated revenue

[160] *Id.*
[161] *Id.* at 6.
[162] *Id.* at 6-7.
[163] *See* Ex. 19 (Davis), at 11.
[164] Ex. 25 (Carter Rebuttal), at 8.
[165] *Id.* at 8-9.
[166] *Id.* at 9.
[167] *Id.*
[168] *Id.* at 10.
[169] Ex. 28 (Givens Rebuttal), at 1-2.
[170] *Id.* at 2.

requirement includes revisions to the projected level of property taxes, feasibility costs, and a correction to the calculation of certain financing costs on deferred account balances.[171] Mr. Givens' updated Rider U revenue requirement in this proceeding was $71,190,000, a decrease of $1.857 million from the revenue requirement sought in the Application.[172]

Mr. Crouch contended that the Company's proposed method of allocating costs to Virginia jurisdictional and Virginia non-jurisdictional customers was consistent with its historical approach of directly assigning distribution plant to the state in which it is physically located.[173] He asserted that it would be inequitable to recover costs associated with the SUP from customers in North Carolina because no lines are being undergrounded in North Carolina as part of the SUP.[174] He testified that over $58 million of distribution plant reliability improvement projects have been installed in the Company's North Carolina service territory over the past five years, and all of those upgrade costs have been directly assigned to North Carolina customers.[175]

Addressing Mr. Dalton's assertion that the Company's proposed cost allocation methodology was previously litigated, he testified that the current proposal is different from the methodology proposed in earlier Rider U proceedings in two ways. First, the methodology that he proposed does not exempt individual non-jurisdictional customers unless the customer is in a class made up of one or more customers served under rate schedules with an applicability provision requiring a demand threshold of at least 500 kW. The customer classes with customers below this threshold are not considered large general service classes.[176] Second, he testified that the methodology he proposed does not adjust the 2014 distribution plant updated to remove exempt customers by a "weight," or by a percentage of actual Rider U plant attributable to specific FERC accounts.[177] Rather, he removed exempt customer using the actual 2017 COSS and then applied the resulting individual FERC account allocation factors to the actual Rider U plant and sum of the Rider U plant. As a result, the Company proposed using the Virginia jurisdictional Rider U allocation factor of 93.15%.[178] He also argued that the previous Rider U methodology based on the 2015 Biennial Review proceeding can no longer be used going forward because customer classification changes have occurred since the earlier cases were decided.[179] He also noted that the previous Rider U allocation methodology, based on the latest biennial review proceeding, utilized data from the year ending December 2014. He observed that that data will be seven years old by the time of the Company's triennial review in 2021.[180] Finally, he testified that all the Company's other Subsection A 6 Riders, the fuel factor, and other rate adjustment clauses utilize the same methodology proposed by the Company in this case, one that incorporates data that is updated on an annual basis.[181]

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171 *Id.*
172 *Id.* at 4.
173 Ex. 30 (Crouch Rebuttal), at 2.
174 *Id.* at 3.
175 *Id.*
176 *Id.* at 6.
177 *Id.* at 7.
178 *Id.* at 4, 7.
179 *Id.* at 8.
180 *Id.*
181 *Id.* at 9.

Mr. Crouch next addressed Mr. Oliver's recommendation that all SUP costs be assigned directly to the jurisdiction where the newly installed distribution plant is located. He noted that this methodology, which allocates SUP costs on a *situs* basis, was similar to the methodology original propose by the Company in the 2015 Rider U proceeding[182] and was challenged by Staff.[183] The Company continues to believe that allocation of costs between Virginia jurisdictional and Virginia non-jurisdictional classes, as opposed to direct assignment, is reasonable and appropriate.[184]

He also disagreed with Mr. Oliver's suggestion that GS-2 and GS-2T customers should be billed using a uniform dollars-per-kW charge.[185]

Mr. Crouch updated the rate design based on the revised revenue requirement, class allocation factors, and the removal of Micron and federal customers from the Virginia jurisdiction. Specifically, he stated that the implementation of the proposed Rider U on February 1, 2019, will incrementally increase the residential customer's monthly bill by $1.33 over the current Rider U. The updated Rider U monthly bill impact is $1.92, based on usage of 1,000 kWh.[186]

DISCUSSION

The Commission denied the Company's first application for approval of Rider U and expressed concern with the magnitude of the proposed program.[187] The Commission suggested that a more limited, lower cost program could reasonably satisfy the statutory requirement for such a program.[188] The Commission stated that "[i]t could be worthwhile to conduct a pilot-type program on a scale far smaller, and much less burdensome to ratepayers, than Dominion proposes herein."[189]

The Commission approved the Company's second application for a more limited SUP, and directed that in any future proceedings, the Company should be able to establish how the SUP has resulted in demonstrated system-wide benefits and document local benefits to the neighborhoods in which the distribution lines have been converted to underground. That approved portion of the SUP program is referred to as Phase One.[190]

In a third case, the Commission approved a continuation of a limited, pilot-type program, but did not approve the more extensive program requested by the Company.[191] The Commission found that as a whole, the Phase Two costs were not reasonably and prudently incurred and was not

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[182] *Application of Virginia Electric and Power Company, For approval of a rate adjustment clause: Rider U, new underground distribution facilities, for the rate year commencing September 1, 2015*, Case No. PUE-2014-00089, 2015 S.C.C. Ann. Rep. 239 ("2015 Rider U").

[183] Ex. 30 (Crouch Rebuttal), at 9.

[184] *Id.* at 10.

[185] *Id.*

[186] *Id.* at 12.

[187] The SUP as originally proposed was a 10 year, approximately $2 billion initiative.

[188] 2015 Rider U.

[189] *Id.* at 241.

[190] 2016 Rider U.

[191] 2017 Rider U.

cost beneficial or just and reasonable. However, the Commission found that an extension of the pilot-type program initiated in Phase One was reasonable and prudent to collect additional data on costs, benefits and reliability. The Commission, therefore, approved a portion of the proposed Phase Two conversions reflecting a total capital investment of $40 million. Both the approved projects and the projects that were not approved in that case are referred to as Phase Two. In this case the Company seeks recovery of costs it has incurred for the remaining Phase Two projects not previously approved.

The SUP is a substantial capital investment initiative intended to reduce outages and shorten restoration times by converting certain outage-prone overhead electric distribution lines and equipment to underground facilities. The Company confirmed that it currently plans to underground a total of approximately 4,000 miles of tap lines[192] over ten years at a capital cost of approximately $2 billion.[193] However, when financing costs are considered the estimated revenue requirement to be recovered from customers over the approximately 42-year useful lives of the plant associated with all phases of the SUP is approximately $5.8 billion.[194]

In this case, Dominion seeks to update Rider U for costs associated with the SUP previously approved by the Commission for Phases One and Two. The Company is also requesting approval of approximately $65.2 million of capital investment which is the balance of the capital investment related to the conversion of 249 miles of overhead tap lines in Phase Two of the SUP, which was disallowed by the Commission in the 2017 Rider U proceeding. In addition, Dominion is requesting approval of approximately $179.0 million of capital investment related to the conversion of 416 miles of overhead tap lines in Phase Three of the SUP. The total capital investment for which the Company requests approval in this case is approximately $244.2 million, excluding financing costs.

Specifically, the Company's revised revenue requirement includes an Actual Cost True-Up Factor and a Projected Cost Recovery Factor for Phase One and the previously approved Phase Two projects of $18,159,000, and Projected Cost Recovery Factors for the remaining Phase Two and Phase Three costs of $53,031,000. The combined Projected Cost Recover Factors and the Actual Cost True-Up Factor result in the total $71.190 million revenue requirement sought to be recovered in the upcoming Rate Year by the Company.[195]

Dominion estimated that the proposed revisions to Rider U will increase the total bill for all residential customers that use 1,000 kWh by approximately $1.33 per month over current Rider U charges, resulting in a total Rider U impact on residential customers of $1.92 per month.[196] The estimated future bill impact for a residential customer using 1,000 kWh per month is expected to grow to $5.16 per month, or $61.92 annually, by 2028. Also, customers will continue to pay for the

[192] Based on information from the Company's public facing website, Dominion has over 50,000 miles of distribution lines. Four thousand miles would then be approximately 8% of all its distribution service.
[193] Tr. 60.
[194] Ex. 19 (Davis), at 4, 13.
[195] The Company originally requested a combined Rider U revenue requirement of $73,047,000, consisting of $18,158,000 for Phase One and the previously approved Phase Two SUP Cost True-Up Factor, and $54,889,000 for the remaining balance of Phase Two and Three in the Projected Cost Recovery Factor; Ex. 2 (Application), at 2; Ex. 7 (Givens Direct), at 5.
[196] Ex. 30 (Crouch Rebuttal), at 12.

amortization of the Rider U plant past 2028 as the assets continue to depreciate over their useful life.

Subsection A 6

Code § 56-585.1 A 6, as amended by SB 966, mandates that the replacement of any subset of a utility's overhead distribution tap lines is in the public interest, deemed to be cost beneficial and prudent, and shall be approved for recovery through a rate adjustment clause, such as Rider U, if the subset (i) is converted to underground service on or after September 1, 2016; (ii) has in the aggregate an average of nine or more total unplanned outage events per mile over a preceding 10-year period; (iii) does not exceed an average cost per customer (including customers served directly down line of the converted tap line) of $20,000, excluding financing costs; and (iv) does not exceed an average cost per tap line mile of $750,000, excluding financing costs.

Subsection A 6, as amended by SB 966, provides in pertinent part:

> To ensure the generation and delivery of a reliable and adequate supply of electricity, to meet the utility's projected native load obligations and to promote economic development, a utility may at any time, after the expiration or termination of capped rates, petition the Commission for approval of a rate adjustment clause for recovery on a timely and current basis from customers of the costs of . . . (iv) one or more new underground facilities to replace one or more existing overhead distribution facilities of 69 kilovolts or less located within the Commonwealth, . . . however, subject to the provisions of the following sentence, the utility shall not file a petition under clause (iv) more often than annually and, in such petition, shall not seek any annual incremental increase in the level of investments associated with such a petition that exceeds five percent of such utility's distribution rate base, as such rate base was determined for the most recently ended 12-month test period in the utility's latest review proceeding conducted pursuant to subdivision 3 and concluded by final order of the Commission prior to the date of filing of such petition under clause (iv). In all proceedings regarding petitions filed under clause (iv) ***or (vi)***, the level of investments approved for recovery in such proceedings shall be in addition to, and not in lieu of, levels of investments previously approved for recovery in prior proceedings under clause (iv) ***or (vi), as applicable. As of December 1, 2028, any costs recovered by a utility pursuant to clause (iv) shall be limited to any remaining costs associated with conversions of overhead distribution facilities to underground facilities that have been previously approved or are pending approval by the Commission through a petition by the utility under this subdivision.*** . . . The replacement of any subset of a utility's existing overhead distribution tap lines that have, in the aggregate, an average of nine or more total unplanned outage events-per-mile over a preceding 10-year period with new underground facilities in order to improve electric service reliability is in the public interest. In determining whether to approve petitions for rate adjustment clauses for such new underground facilities that meet this criteria, and in determining the level of costs to be recovered thereunder, the Commission shall

liberally construe the provisions of this title. ~~There shall be a rebuttable presumption that the~~ ***The*** conversion of ***any*** such ***facilities*** ~~will~~ ***on or after September 1, 2016, is deemed to*** provide local and system-wide benefits~~, that such new underground facilities are~~ ***and are to be*** cost beneficial, and ~~that~~ the costs associated with such new underground facilities are ***deemed to be*** reasonably and prudently incurred ***and, notwithstanding the provisions of subsection C or D, shall be approved for recovery by the Commission pursuant to this subdivision, provided that the total costs associated with the replacement of any subset of existing overhead distribution tap lines proposed by the utility with new underground facilities, exclusive of financing costs, shall not exceed an average cost per customer of $20,000, with such customers, including those served directly by or downline of the tap lines proposed for conversion, and, further, such total costs shall not exceed an average cost per mile of tap lines converted, exclusive of financing costs, of $750,000.***[197]

Statutory Criteria for Cost Recovery

Dominion used an events-per-mile metric to identify and select candidate tap lines for underground conversions. Dominion calculated this metric as the ratio of the number of outage events for a tap line over a 10-year period divided by the length of the line in miles. The result of this calculation for Phase Two of the SUP yielded an average rate of 14.27 outage events per mile over a 10-year period. Phase Three projects experienced an average rate of approximately 14 outage events per mile over the past 10-year period. Phases Two and Three of the SUP appear to meet the minimum statutory events-per-mile metric of "an average of nine or more total unplanned outage events per mile over a preceding 10-year period."

The two cost criteria set forth in Subsection A 6 are (i) an average cost-per-customer cap of $20,000, and (ii) an average cost-per-mile cap of $750,000. Neither cost cap includes financing costs. Dominion calculated an average cost per customer of $11,912 for conversion of tap lines in Phase Two and $13,299 for conversion of tap lines in Phase Three, both are under the statutory cap of $20,000. For the average cost-per-mile metric, Dominion calculated an average cost per mile of $422,496 for Phase Two and $430,000 for Phase Three, both are under the statutory cap of $750,000.

Staff investigated and confirmed Dominion's calculated metrics; and, therefore, concluded that the conversion of tap lines included in Phases Two and Three meet the minimum statutory requirements. Staff did not oppose Dominion's requested cost recovery in this proceeding.[198]

Consumer Counsel Witness Norwood also confirmed that, except for eight distribution tap lines with conversion dates prior to the statutory *terminus post quem*, the Phase Two and Phase Three conversions appeared to meet the statutory eligibility requirements.

[197] Code § 56.585.1 A 6 (amended language struck through or italicized for emphasis).

[198] A difference in the recommended allocation methodology proposed by the Company and the methodology proposed by Staff affects the total revenue requirement.

The General Assembly removed the Commission's discretion regarding cost recovery of the replacement of overhead distribution tap lines with underground facilities when certain defined statutory criteria are met. The General Assembly thus mandated that the Company's SUP is in the public interest, is deemed to be cost beneficial and prudent, and I recommend the Commission approve those costs for recovery through Rider U when, except as discussed below, the statutory metrics are met.

SUP Projects Converted Prior to September 1, 2016

Consumer Counsel Witness Norwood identified eight tap line conversions completed prior to September 1, 2016. Those conversions, according to Mr. Norwood, failed to meet the statutory criteria declaring the associated costs to be reasonably and prudently incurred which mandated cost recovery.[199] He noted that the statutory declarations are explicitly limited in application to "the conversion of any such facilities" converted "on or after September 1, 2016." He testified that the Company's own data provided in response to Staff Interrogatory 5-48[200] listed a "conversion date" prior to September 1, 2016, for eight out of the 3,334 tap lines. Consumer Counsel contended that those lines should be treated in accordance with the Commission's decision in the 2017 Rider U Final Order that denied Phase Two projects in excess of the approved pilot limit of $40 million. He, therefore, recommended that the capital cost of $1,239,696 associated with those eight tap lines be excluded from Rider U cost recovery.[201]

The Company supplemented its response to Staff Interrogatory 5-48 to include an additional column of data titled "Closed to Plant Date." For the eight tap lines questioned by Mr. Norwood, the Company identified a "Closed to Plant Date" on or after September 1, 2016.[202] Dominion asserted this is the date the tap lines should be considered converted since "there is a period for verification of construction units (as-building), final billing, and reconciliation of the initial design with work in the field" after the actual construction is completed.[203] In other words, the Company wants the Commission to consider the date a converted project is closed for accounting purposes as the conversion date.

Additionally, Company Witness Carter corrected his direct testimony at the hearing to reflect that one of the eight tap lines, device 82612F22, was in fact a Phase One tap line conversion.[204] Mr. Norwood's list of projects in Phase Two converted before September 1, 2016, was reduced to seven which reduced his recommended disallowance from $1,239,696 to $1,006,673.[205]

Lastly, the Company argued that even if the Commission rejects its explanation regarding the conversion date and excludes the seven tap lines from Phase Two recovery, the Company

[199] Ex. 13 (Norwood), at 8.
[200] Ex. 5.
[201] Ex. 13 (Norwood), at 8-9; Tr. 113.
[202] Ex. 5; Ex. 25 (Carter Rebuttal), at 9.
[203] Ex. 5; Tr. 119, 183.
[204] Tr. 54.
[205] Tr. 112-13.

should be allowed to recover the costs of those projects under Phase One. Phase One was limited to cost recovery through Rider U of $122.5 million and the Company has only sought recovery of $121.2 million for Phase One investments.[206]

In my opinion, Subsection A 6 does not refer to when a tap line project is closed per books for accounting purposes. Rather, it applies the new standard for cost recovery to those facilities converted on or after September 1, 2016. Phase Two SUP projects converted before September 1, 2016, were subject to the Commission's discretion, and the Commission previously limited cost recovery for Phase Two projects. SB 966 removed that discretion for projects that met defined criteria only for projects converted, not closed to books for accounting purposes, on and after September 1, 2016, rendering a legislative finding that costs associated with covered projects were deemed to be reasonable and prudently incurred. I find costs above the approved $40 million cap for Phase Two projects converted prior to September 1, 2016 were not reasonably incurred. I also find that it would not be appropriate to re-classify Phase Two projects as Phase One projects. Even the Company admitted that re-classification would create complications.[207] Therefore, I recommend that the Commission reduce revenue requirement to reflect the previously disallowed Phase Two costs of $1,006,673.

Additional Factors to Consider when Selecting SUP Projects

Although Staff confirmed that Phases Two and Three projects meet the statutory criteria, at a granular level, Staff identified the highest cost-per-customer tap line in Phase Two of the SUP and the highest cost-per-customer tap line conversions in Phase Three at an estimated lifetime revenue requirement per customer of $597,199 and $759,565, respectively.[208] Those two lines were among the 14 highest cost conversions in Phases Two and Three that ranged in cost from $159,710 to $299,149 per customer, well above the average cost-per-customer cap of $20,000 set forth in the statute.[209] Mr. Upton also recommended that in addition to the number of outages as is required by Subsection A 6, the Company should consider the length of the durations. Staff recommends that, going forward, the Company consider additional factors related to customer count and outage duration, in addition to the statutory metrics, to improve the economic and operational efficiency of the SUP, and avoid some of the very high cost-per-customer projects identified by Staff Witness Dalton.

Subsection A 6 sets forth the minimum statutory metrics that Dominion must consider, but does not preclude the Company from taking other considerations into account. Indeed, Company Witness Bradshaw explained that in a continuing effort to enhance the program, the Company looks for the best places to put the underground facilities.[210] Mr. Bradshaw stated that the Company uses the events-per-mile metric to develop its initial list of candidate tap lines to create a baseline so potential candidate tap lines can be compared.[211] He noted that the Company considers process refinements to identify the best tap lines to convert, but he was opposed to Staff's recommendation.

[206] Tr. 127-28.
[207] Company Brief, at 4 n.4.
[208] Ex. 22 (Dalton), at 7-8.
[209] *Id.* at 4-5, 6-8.
[210] Tr. 174.
[211] Ex. 3 (Bradshaw Direct), at 7.

Staff does not recommend the Company consider customer count and outage duration in lieu of the statutory metrics required by law, but rather in addition to, much like the Company's further investigation of tap lines. I find that once the list of SUP projects that meet the statutory metrics is compiled, it is reasonable to consider additional factors to finalize the projects for underground conversion as the Company already does to enhance and refine its process. I recommend those factors also include customer count and outage duration as identified by Staff.

Jurisdictional Allocation and Class Revenue Apportionment

Dominion proposed a new allocation method in this case. The new allocation method first assigned SUP costs to the Virginia jurisdictional and Virginia non-jurisdictional classes based on the Company's 2016 COSS by applying the number of customers, class peak demand, and non-coincident peak demand in the seven FERC plant accounts that contain Rider U investment.[212] The Company also removed customers it considered exempt in accordance with Subsection A 6 in the development of the jurisdictional allocation factor. Using the updated 2017 COSS the Company computed a Virginia jurisdictional Rider U allocation factor of 93.15% for the Projected Cost Recovery Factor.[213] The Company used the prior Rider U cost allocation methodology resulting in an allocation factor of 89.1650% for purposes of developing the Actual Cost True-Up Factor.[214]

The Company also changed the way it classified federal customers citing to Commission approval of the Company's proposed cost allocation and rate design in the 2017 DSM proceeding,[215] to support the Company's treatment of federal customers as non-jurisdictional, and exempt the federal large general service sub-class from recovery under Subsection A 6. The Company proposed to allocate the revenue requirement among the classes based on each classes' Rider U distribution plant, weighted to reflect actual Rider U investment, in the same manner the Company proposed to develop the Rider U jurisdictional allocation factor.[216]

Staff believes that the currently approved methodologies for jurisdictional allocation and class revenue apportionment remain appropriate. Staff recommended that the Company be required to continue using the methodology approved by the Commission in the 2016 Rider U proceeding which utilized data from the Company's 2014 COSS developed in the 2015 Biennial Review. Staff also contended that the Company's proposed alternative allocation methodology and revenue apportionment are not appropriate and are substantially similar to methodologies the Commission previously considered and rejected.

Staff contended the Company's approach to class allocation is substantially similar to the class cost allocation methodology rejected by the Commission in earlier cases. Staff continued to

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212 Ex. 8 (Crouch Direct), at 5-7.
213 Ex. 30 (Crouch Rebuttal), at 4.
214 Ex. 8 (Crouch Direct), at 7.
215 Petition of Virginia Electric and Power Company, For approval to extend an existing demand-side management program and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia, Case No. PUR-2017-00129, Order on Petition for Limited Reconsideration (May 23, 2018) ("2017 DSM proceeding").
216 Ex. 30 (Crouch Rebuttal), at 10-12.

support use of the 2015 COSS used in the 2015 Biennial Review largely because the 2017 COSS data was introduced in the Company's rebuttal and the parties did not have the opportunity to fully review the content.[217] Nonetheless, Staff Witness Dalton, as part of his surrebuttal, presented a calculation of the jurisdictional allocation factor using the currently-approved methodology supported by Staff, but incorporating the 2017 COSS data.[218] That calculation resulted in a factor of 89.4487% as opposed to the factor of 89.0331 % resulting from use of the 2015 COSS data, a difference that Staff Witness Dalton deemed to be immaterial.[219]

The currently approved jurisdictional and class revenue apportionment methodologies and treatment of exempted classes, recognize that all customers are intended to benefit from the SUP through improved reliability and should share in the costs, unless exempted by statute. The Commission determined the appropriate jurisdictional allocation and class revenue apportionment methodology in the 2016 Rider U proceeding. The straight-forward methodology totals the plant in each of the relevant FERC distribution-related accounts and uses the ratio of jurisdictional to non-jurisdictional plant as a composite allocation factor. The 2018 amendments to Subsection A 6 clarify the General Assembly's determination that the SUP "is deemed to provide local and system-wide benefits . . . ." The plain language of the statute creates a limited exemption for certain enumerated classes and non-jurisdictional customers, but I find no compelling reason to change the methodology previously approved by the Commission. I also find, however, that it is reasonable to update Staff's methodology to reflect the more current 2017 COSS data for purposes of this case.

Allocation to the North Carolina Jurisdiction

Consumer Counsel Witness Norwood asserted that the SUP costs should be allocated among the Company's jurisdictions on its distribution system, including its North Carolina jurisdiction. He based his assessment on the General Assembly's determination that the SUP investment provides system-wide benefits. Mr. Norwood's proposal would, in effect, allocate a small portion of the Rider U revenue requirement, approximately 5 %, to the North Carolina jurisdiction.[220]

Staff Witness Dalton recommended a different allocation factor, but he testified that Mr. Norwood's recommendation was not unreasonable. He observed that through May 11, 2018, only 18,093 residential customers have been undergrounded as part of the SUP, but approximately 2,249,545 residential customers in Virginia were paying for the SUP through Rider U.[221] He calculated the Virginia jurisdictional allocation factor using Staff's recommended methodology and incorporated Consumer Counsel's recommendation to allocate a portion of the SUP costs system-wide, including the North Carolina jurisdiction. That allocation factor would be 84.4915%.[222]

The Company and AOBA take exception with Mr. Norwood's recommendation. AOBA argued that the SUP predominately provides local instead of system-wide benefits. The Company

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[217] Staff Brief, at 17.
[218] Ex. 23.
[219] Tr. 167.
[220] Tr. 130.
[221] Ex. 22 (Dalton), at 16-17.
[222] *Id.* at 17.

argued that it is inconsistent with how the Company has historically allocated costs of distribution plant to the state in which it is physically located. Specifically, Company Witness Crouch explained that the SUP only addresses upgrades to distribution plant located in Virginia. For that reason, the Company assigns all those costs directly to Virginia and then allocated the costs between the Virginia jurisdictional and Virginia non-jurisdictional customers.[223] Dominion also observed that the SUP is a public policy initiative directed by the Virginia General Assembly; and, therefore, it is not appropriate to assign costs associated with Virginia distribution plant to the North Carolina jurisdiction.

On this issue, I tend to agree with the Company. It is Virginia distribution plant, and although the General Assembly has deemed the SUP to have system-wide benefits, it also recognized converting tap lines to underground has local benefits. I do not recommend allocating a portion of the costs associated with the Virginia SUP to Dominion's North Carolina jurisdiction.

AOBA Allocation Methodology and Rate Design

AOBA recommended that costs to be recovered through Rider U for facilities converted to underground as part of the SUP be primarily assigned on a *situs* basis. AOBA Witness Oliver contended that most of the undergrounded facilities installed as part of the SUP benefit only those customers directly served by, or downstream of, the converted facilities.

Staff did not support AOBA's recommendation to directly assign the costs locally. Staff observed that the Company made a similar proposal in the 2015 Rider U proceeding, which Staff opposed. Staff emphasized that the purpose of the SUP is to benefit the entire system, not just the customers whose service is being directly undergrounded.[224]

The Company also observed that the AOBA allocation approach was similar to a direct assignment methodology proposed by the Company in the 2015 Rider U proceeding,[225] which was opposed by Staff, and not adopted by the Commission. The Company continues to believe that allocation of costs between the Virginia jurisdictional and Virginia non-jurisdictional classes, as opposed to direct assignment, is appropriate.

AOBA's approach, which would allocate costs based on *situs*, is also contrary to Consumer Counsel's observation that the statute now considers the SUP to provide system-wide benefits. Again, however, Subsection A 6 deems the SUP to have both local and system-wide benefits, not local only or system-wide only. In my view, AOBA has not provided sufficient justification to change the allocation methodology to a *situs* approach. I find Virginia system-wide allocation as has been done in previous SUP cases to continue to be reasonable and appropriate.

AOBA also raised rate design issues related to the GS-2 and GS-2T classes. Its witness, Mr. Oliver, proposed a modified version of the Company rate design for GS-2 and GS-2T customers. The key difference was the way the overall revenue requirement for those rate schedules was distributed between high and low load factor customers within those classes. Both

[223] *Id.* at 4; Ex. 30 (Crouch Rebuttal), at 2.
[224] Staff Brief, at 19.
[225] 2015 Rider U.

applied a combination of demand (dollar per kW) and distribution (cents per kWh) charges. Both proposed applying demand charges only to customers' bills that reflect load factors greater than 50% and cents per kWh charges to customers' bills having load factors equal to or less than 50%. However, Mr. Oliver developed charges based on a uniform dollar per kW basis. Here too, the Commission has previously considered and rejected a similar rate design. In my opinion, sufficient justification has not been provided to change the previously approved rate design.

Revenue Requirement

In its Application, the Company requested approval of a revenue requirement of $73.047 million. In rebuttal, that revenue requirement was adjusted to $71.190 million. Staff originally recommended a revenue requirement of $70.829 million, but later modified its recommendation to $69.905 million. The difference between the revenue requirements of the Company and Staff is largely the result of the different jurisdictional allocation methodologies. My recommended revenue requirement of approximately $69.5 million removes seven Phase Two projects for which the actual underground construction conversion was completed before September 1, 2016, and incorporates Staff's allocation methodology updated to reflect the Company's 2017 COSS data. Specifically,

Previously Approved Phases (One and Two)	
Projected Cost Recovery Factor	$13.5 million
Actual Cost True-Up Factor	$5.9 million
Less Voluntary Credit[226]	($1.8 million)
Total	**$17.6 million**
Remaining Phase Two*	
Projected Cost Recovery Factor	**$15.7 million**
Phase Three	
Projected Cost Recovery Factor	**$36.2 million**
Total Rider U	**$69.5 million**

*Excluding seven projects considered to be converted prior to September 1, 2016.

Additional Information in the Annual SUP Reports

Staff Witness Upton recommended that the Company be directed to include additional data in its annual SUP reports.[227] Specifically, he recommended that Dominion also provide SAIDI,

[226] 2016 Rider U; Ex. 7 (Givens Direct), at 14.
[227] Ex. 21 (Upton), at 18-20.

SAIFI, and CAIDI data not just for tap lines converted, but also on a regional and system-wide basis, both excluding and including major events. Dominion agreed to collaborate with Staff to develop those additional reporting metrics.[228] Dominion also agreed the data requested by Staff in Interrogatory 5-48[229] would be useful to incorporate in the SUP Annual Report.[230] I find the additional information will better inform Staff's assessment and future Commission action. 181120265

FINDINGS AND RECOMMENDATIONS

Based upon the evidence presented in this case, and for the reasons set forth above, I find that:

1. Seven of the Phase Two projects were converted to underground facilities before September 1, 2016, and the costs, totaling $1, 006,673, associated with those projects should be excluded from the revenue requirement;

2. Use of a jurisdictional allocation factor of 89.0331% based on Staff's methodology and the Company's 2017 COSS data is reasonable; and

3. The Company's Rider U revenue requirement is approximately $69.5 million for recovery through Rider U during the Rate Year commencing February 1, 2019.

Accordingly, **I RECOMMEND** the Commission enter an order:

1. ***ADOPTING*** the findings of this Report; and

2. ***APPROVING*** the updated Rider U consistent with the recommendations in this Report.

COMMENTS

The parties are advised that pursuant to Commission Rule 5 VAC 5-20-120 C of the Commission's Rules of Practice and Procedure, any comments to this Report must be filed with the Clerk of the Commission in writing, in an original and fifteen (15) copies, within twenty-one (21) days from the date hereof. The mailing address to which any such filing must be sent is Document Control Center, P.O. Box 2118, Richmond, Virginia 23218. Any party filing such comments shall attach a certificate to the foot of such document certifying that copies have been mailed or delivered to all counsel of record and any such party not represented by counsel.

Respectfully submitted,

Deborah V. Ellenberg

Deborah V. Ellenberg
Chief Hearing Examiner

[228] Ex. 24 (Bradshaw Rebuttal), at 13-14; Ex. 25 (Carter Rebuttal), at 6-7.
[229] Ex. 5.
[230] Ex. 25 (Carter Rebuttal), at 7.

The Commission's Document Control Center is requested to mail or deliver a copy of the above Report to all persons on the official Service List in this matter. The Service List is available from the Clerk of the State Corporation Commission, c/o Document Control Center, 1300 East Main Street, Tyler Building, First Floor, Richmond, VA 23219.